3.7 Air Quality

The proposed Energy Facility would use advanced combined-cycle gas turbine technology, clean-burning natural gas, and high-efficiency air emission control technology. Air quality modeling was conducted for the Facility using standard EPA modeling techniques and meteorological data collected at the site. Impacts for all of the criteria pollutants were well below the applicable ambient air quality standards. Therefore, it was concluded that no significant air quality impacts would occur near the Energy Facility.

Cumulative impact analysis indicated that emissions from the Energy Facility, combined with those of other existing sources in the area, would not result in concentrations above the federally mandated National Ambient Air Quality Standards (NAAQS) or Prevention of Significant Deterioration (PSD) increment levels for the criteria pollutants analyzed. In addition, the analysis identified no cumulative impacts to visibility in Class I areas resulting from Energy Facility emissions combined with those of other power generating and related facilities in the area.

The information presented in this section is based on the studies and analysis conducted for the SCA as amended by Amendments No. 1 and No. 2, filed with EFSC on July 25, 2003, and October 15, 2003, respectively.

3.7.1 Affected Environment

3.7.1.1 Climate

The proposed Energy Facility would be located in the south-central part of Oregon, near the town of Bonanza, in an area characterized by dry, warm summers and cold winters. Climatic summary data were obtained from the Western Regional Climate Center Web site (www.wrcc.dri.edu/cgi-bin/cliRECtM.pl?orklam) for a site at Klamath Falls, about 23 miles northwest of the Energy Facility site. During the period of data collection, from 1928 to 2001, the annual average precipitation was approximately 13.7 inches, with monthly mean temperatures ranging from 29.8 degrees Fahrenheit (°F) in January to 68.5°F in July.

A meteorological monitoring station was installed at the Energy Facility site in October 2001 to collect data suitable for use in an atmospheric dispersion modeling analysis. The parameters measured included wind speed, wind direction, and temperature. The sensors were mounted on a 32.8-foot-tall tower designed to meet the requirements for collecting onsite data for permitting and modeling under EPA PSD regulations (40 CFR 52.21).

The dispersion modeling analysis performed for the PSD application was for the period of October 28, 2001 through October 28, 2002. As indicated in Figure 3.7-1, predominant winds for the period of record were from the west-northwest (approximately 19 percent) and southeast (approximately 11 percent).

3.7.1.2 Odor

There are no existing operations associated with the Energy Facility site that generate significant odors.

3.7.1.3 Ambient Air Quality Standards

Ambient Standards for Criteria Pollutants. The Clean Air Act of 1970 empowered EPA to establish air quality standards for six common air pollutants: ozone, carbon monoxide (CO), lead, nitrogen dioxide (NO_2), particulates, and sulfur dioxide (SO_2). These are also referred to as criteria pollutants. The standards include primary standards designed to protect public health and secondary standards to protect public welfare. These NAAQS reflect the relationship between pollutant concentrations and health and welfare effects. ODEQ adopted standards similar to the NAAQS, and included standards for SO_2 that are more stringent than the Federal standards. Table 3.7-1 summarizes the Federal and state primary and secondary standards for the six pollutants, and the averaging time for determining compliance with the standards. It also presents the allowable increments (increases above background) under EPA's PSD program that would be applicable to the Energy Facility.

Prevention of Significant Deterioration. ODEQ has been delegated authority to administer the PSD program for major sources constructed or modified within the state. PSD regulations apply to proposed new or modified sources located in an attainment area that have the potential to emit criteria pollutants at a level which would define the source as "major" (40 CFR Part 51). The Energy Facility is a fossil fuel-fired steam electric plant, which is one of 28 categories of facilities considered major if emissions are greater than 100 tons per year of one or more criteria pollutants.

The PSD review process evaluates the potential impacts of the proposed source on ambient air quality and provides a review of the Best Available Control Technology (BACT). PSD restricts the degree of ambient air quality deterioration that is allowed. Increments for criteria pollutants are based on the PSD classification of the area. All areas in the Pacific Northwest are divided into either Class I or Class II areas. Class I areas are specifically identified federally protected wilderness areas and national parks. The PSD rules ensure that the Class I areas experience the least amount of deterioration. Class II areas are designed to allow for moderate, controlled growth.

The Class I areas within 200 kilometers of the Energy Facility site are shown in Table 3.7-2. The area around the Energy Facility site is designated Class II. Class I and Class II PSD increments are shown with the ambient air quality standards in Table 3.7-1.

Federal, State, and Local Emission Limits. As part of the PSD process, emission limits are established for the facility via a PSD permit issued by ODEQ. Emission limits are set based on the BACT determination. The BACT analysis identifies pollutant-specific alternatives for emission control, and the costs and benefits of each alternative technology. ODEQ determines the most appropriate control technology on a case-by-case basis considering the associated economic, energy, and environmental impacts. The utilization of BACT ensures reduced emissions of criteria pollutants. For example, use of natural gas as a fuel is considered BACT for certain pollutants because of its lower emissions over other fuels, such as fuel oil or coal. Combustion controls also reduce criteria pollutants by optimizing combustion and reducing pollutants emitted in the exhaust stream.

The determination of BACT during the ODEQ review of the PSD permit defines the emission limits for the Energy Facility.

Hazardous Air Pollutant Regulations. The Clean Air Act Amendments of 1990 required EPA to list and promulgate National Emission Standards for Hazardous Air Pollutants (NESHAP) in order to control, reduce, or otherwise limit the emissions of hazardous air pollutants from specific source categories. Stationary combustion gas turbines are on the list of source categories that are subject to emission standards if the total hazardous air pollutant (HAP) emissions could exceed the major source thresholds. The Energy Facility would not be above the HAP major source thresholds and so would not be subject to the stationary combustion gas turbine NESHAP. However, even if the NESHAP did apply, EPA has indicated that the lean premix combustion turbine technology to be utilized in the Energy Facility would meet the HAP standards even without consideration of the additional, planned add-on controls. The oxidation catalysts proposed for use at the Energy Facility would provide substantial additional hazardous air pollutant control beyond what EPA is expected to require under the NESHAP.

3.7.1.4 Existing Air Quality

The proposed Energy Facility would be located in an area designated as attainment for all criteria air pollutants. The city of Klamath Falls, located approximately 34 miles to the northwest of the Energy Facility, is currently classified as a nonattainment area for PM_{10} and CO. However, the Oregon Environmental Quality Commission recently passed new rules to have the area reclassified as attainment for PM_{10} and CO. Nonetheless, the Energy Facility performed modeling demonstrating that its emissions would not cause any substantial impacts within the city of Klamath Falls.

There are several major sources of air emissions currently operating within 50 miles of the Energy Facility. A natural gas pipeline compressor station, consisting of two gas-fired turbines, is owned and operated by PG&E Gas Transmission Northwest (Bonanza Station 14) and is located 3.3 miles south of the proposed Energy Facility. These units emit the same pollutants as the combustion turbines and heat recovery steam generators (HRSGs) at COB, although in a smaller quantity. This source is under the jurisdiction of ODEQ's Eastern Regional Office, and is operating under a Title V (of the CAA) operating permit. Data for emissions from this source were obtained from ODEQ for use in the competing source dispersion analysis.

Klamath Cogeneration Project (KCP) is located approximately 22 miles west of the Energy Facility site and consists of two combustion turbines and HRSGs. The Collins Products, LLC, mill is adjacent to the KCP and consists of a variety of wood products sources, with PM_{10} as the primary pollutant. A permit application was recently submitted requesting authority to build the Klamath Generation Facility (KGF) adjacent to the KCP. The KGF would consist of two combustion turbines and HRSGs. It is not known if or when that facility would receive permits or be constructed.

3.7.2 Environmental Consequences and Mitigation Measures

<u>Impact 3.7.1 Construction of the Energy Facility, natural gas pipeline, water supply pipeline, and electric transmission line would result in air emissions of fugitive dust and combustion exhaust.</u>

Emissions during the approximately 23-month construction process would consist of fugitive dust and combustion exhaust emissions from construction equipment and vehicles.

Fugitive dust emissions would result from dust stirred up during site preparation, onsite travel on paved and unpaved surfaces, and during aggregate and soil loading and unloading operations. Wind erosion of disturbed areas could also contribute to fugitive dust.

Combustion emissions would result from diesel-fired construction equipment, various diesel-fueled trucks, diesel-powered equipment (e.g., welding machines, electric generators, air compressors, water pumps), locomotives delivering equipment, and vehicle emissions from workers commuting to the construction site. Emissions could also occur during paving and painting of Energy Facility buildings and equipment.

These emissions would be of a temporary nature, and would be mitigated by use of best management practices to control fugitive dust and other incidental emissions. Controls may include the following actions:

- Use water spray as necessary to prevent visible dust emissions.
- Minimize dust emissions during transport of fill material or soil by wetting down or by ensuring adequate freeboard on trucks.
- Promptly clean up spills of transported material on public roads by frequent use of a street sweeper machine.
- Cover loads of hot asphalt to minimize odors.
- Keep all construction machinery engines in good mechanical condition to minimize exhaust emissions.

These standard measures would avoid significant, construction-related air quality impacts.

<u>Recommended Mitigation Measures</u>. No mitigation measures are recommended beyond those included in the proposed project.

<u>Impact 3.7.2. Operation of the Energy Facility would result in the emission of criteria pollutants.</u>

Combustion turbines and duct burners associated with the HRSGs at the proposed Energy Facility would use natural gas as the only fuel. Combustion of natural gas results in emissions of PM_{10}, NO_X, SO_2, CO, and volatile organic compounds (VOCs). The features listed below, which are incorporated into the Energy Facility design, would be employed to reduce air emissions:

- Combined-cycle technology that would provide energy conversion from natural gas to electricity with efficiencies that exceed 50 percent
- Combined effect of dry low NO_x combustion technology on the combustion gas turbines and Selective Catalytic Reduction (SCR) technology incorporated into the HRSGs that would reduce total NO_x emissions to 2.5 ppmvd
- Oxidation catalyst controls incorporated into the HRSGs that would reduce CO emissions to 2.0 ppmvd and VOCs to 7 lbs/hr from each stack

The Energy Facility would include four combustion turbines, four HRSGs equipped with supplemental duct firing, and other equipment. Supplemental duct firing with low NO_x

burners would be used for additional peaking demand, particularly during the summer months.

Combustion turbines and duct burners associated with the HRSGs would be equipped with dry, low-NO_x (DLN) burners. The NO_x emissions from the combustion turbines and duct burners associated with HRSGs would be further controlled using SCR. Use of SCR, while reducing NO_x emissions, results in ammonia (NH_3) emissions, which are commonly referred to as ammonia slip.

CO emissions from the combustion turbines and duct burners associated with HRSGs would be controlled using an oxidation catalyst. Use of an oxidation catalyst for controlling CO emissions also results in control of VOC emissions.

Table 3.7-3 summarizes the maximum annual emission rates of the criteria pollutants from the combustion turbines, HRSGs, and the fire pump. As a worst-case estimate, the proposed annual emission rates of the various criteria pollutants were based on the maximum short-term emission rates under various operating scenarios times 8,760 hours of operation per year (6,600 hours per year for the duct burners). The maximum hours of operation for the diesel fire pump would be 1 hour per day, 1 day per week, with an annual maximum of 52 hours per year.

An air quality impact assessment was conducted to evaluate compliance of the Energy Facility with applicable regulatory requirements. The assessment was done through an air quality modeling analysis and was described in detail in the PSD permit application (COB Energy Facility, LLC, August 2002), and revised in December 2002 and July 2003.

The air quality modeling was conducted using standard EPA modeling techniques. The EPA-approved Industrial Source Complex Short Term (ISCST3) dispersion model was used with wind data from the onsite meteorological station to model the ambient concentrations of pollutants within roughly 10 miles of the proposed Energy Facility. The EPA-approved CALPUFF model was used to predict pollutant concentrations at long-range receptors more than about 10 miles from the Energy Facility. Results were compared with EPA criteria, including state and Federal ambient air quality standards, Class II significant impact levels, PSD Class I and Class II increments, and proposed EPA Class I significance levels.

Table 3.7-4 summarizes the results of the criteria pollutant air quality analysis. With the addition of conservative background concentrations for 1-hour CO and for 24-hour and annual PM_{10}, impacts for all of the criteria pollutants were well below the applicable ambient air quality standards, and PSD Class II increments or air quality significant impact levels. Therefore, it was concluded that the Energy Facility would cause no significant air quality impacts.

<u>Recommended Mitigation Measures</u>. No mitigation measures are recommended beyond those included in the proposed project.

<u>Impact 3.7.3. Operation of the Energy Facility would result in emissions of greenhouse gases.</u>

Emissions of carbon dioxide (CO_2) for the Energy Facility were estimated as a part of the demonstration of compliance with OAR 345-024-0560, as presented in the SCA. It is estimated that up to 2.7 million tons per year of CO_2 could be emitted from the proposed

Energy Facility. Carbon dioxide emissions greater than 0.675 pounds per kilowatt-hour of net electric power output would be offset as required by OAR 345-024-0550. The excess emissions, 15.349 million tons over 30 years, would be offset by payment of more than $13.6 million to The Climate Trust. The Climate Trust would use these funds to finance CO_2 mitigation projects.

Recommended Mitigation Measures. No mitigation measures are recommended beyond those included in the proposed Energy Facility design.

Impact 3.7.4. Operation of the proposed Energy Facility would result in emissions of hazardous air pollutants.

Table 3.7-5 summarizes HAP emissions from the Energy Facility. Benzene, toluene, xylenes, polycyclic aromatic hydrocarbons (PAH), formaldehyde, and other organic compounds associated with the combustion of natural gas would be released into the atmosphere from the stacks associated with combustion turbines.

The oxidation catalyst used to reduce CO emissions would be effective in controlling volatile organic HAP emissions such as formaldehyde. For this project, it was assumed that the oxidation catalyst would provide 55 percent destruction of volatile organic HAPs, although EPA has indicated that the destruction efficiency could be significantly higher. The NO_x emissions from the combustion turbines and HRSG duct burners would be continuously monitored, allowing continuous feedback to the ammonia supply system. This would allow the levels of ammonia used in the SCR to be adjusted, thus minimizing ammonia slip.

Recommended Mitigation Measures. No mitigation measures are recommended beyond those included in the proposed project.

Impact 3.7.5. Operation of the Energy Facility could Impact Air Quality-Related Values in federally managed Class I areas in the region.

PSD regulations require an assessment of the project's impact to Air Quality Related Values (AQRVs) in Class I areas. AQRVs include regional visibility or haze, the effects of primary and secondary pollutants on sensitive plants, the effects of pollutant deposition on soil and water bodies, and effects associated with secondary aerosol formation. These requirements provide special protection for Class I areas. Table 3.7-1 lists the Class I areas near the Energy Facility site.

The EPA-approved CALPUFF modeling system was used for modeling the long-range transport of pollutants from the generation plant. CALPUFF is EPA's proposed model for predicting long-range transport and dispersion accounting for downwind chemical reactions within the emitted plume. Features of the CALPUFF modeling system include secondary aerosol formation, gaseous and particle deposition, wet and dry deposition processes, complex three-dimensional wind regimes, and the effects of humidity on regional visibility. The modeling procedures used follow the recommendations of the Interagency Agency Workgroup on Air Quality Modeling and the Federal Land Managers Air Quality Related Values Workgroup (Federal Air Quality Land Manager's Workgroup, 2000).

Class I Area Increment Consumption. PSD regulations require the Energy Facility to model air pollutant concentrations at the Class I areas, and compare the modeled concentrations to the allowable PSD Class I increments. Long-range modeling of impacts to the distant Class I areas was done using the CALPUFF modeling system in accordance with Federal guidance and state and Federal review. Table 3.7-6 provides the results of the Class I PSD increment analysis. The modeled maximum concentrations at all Class I areas were well below the allowable Class I increments for all criteria pollutants. The modeled maximum concentrations at all Class I areas were also below the proposed EPA Class I significance levels.

Nitrogen and Sulfur Deposition at Class I Areas. The CALPUFF modeling system was used to estimate the Energy Facility's potential contribution to total nitrogen and sulfur deposition in the Class I areas. Soil, vegetation, and aquatic resources in Class I areas are potentially influenced by nitrogen and sulfur deposition. Federal Guidance indicates that net increases in the annual deposition exceeding 5 kilograms per hectare per year (kg/ha/yr) for nitrogen or 3 kg/ha/yr for sulfur would constitute a significant impact.

Total annual nitrogen and sulfur deposition fluxes were calculated by summing the contributions of the gases directly emitted with the secondary aerosol products formed as predicted by CALPUFF's chemistry and deposition algorithms. The annual deposition fluxes were estimated based on emission rates that assumed that duct firing would occur 6,600 hours per year.

No significant impacts on sulfur and nitrogen deposition rates are predicted to occur as the result of emissions from the proposed Energy Facility. Deposition results for nitrogen and sulfur are summarized in Table 3.7-7 for each Class I area. Incremental deposition rates attributable to the proposed Energy Facility are less than the screening criteria levels currently recommended by Region 6 staff (Mr. Bob Bachman) of the USDA Forest Service for all Class I areas except Gearhart Wilderness Area, which was predicted to slightly exceed the nitrogen deposition screening criterion. These screening criteria are 0.005 kg/hectare per year for nitrogen and 0.003 kg/hectare per year for sulfur at each Class I area, which represent 0.1 percent of the maximum load of 5 kg/hectare per year for nitrogen and 3 kg/hectare per year for sulfur identified in the *Guidelines for Evaluating Air Pollution Impacts on Class I Wilderness Areas in the Pacific Northwest* (USDA Forest Service, May 1992). Based on these deposition modeling results, the proposed Energy Facility has demonstrated that it would not have a significant impact on sulfur and nitrogen deposition rates in the Class I areas.

Regional Haze Assessment. PSD regulations require the Energy Facility to model impacts on regional haze at the nearest Class I areas. Regional haze is generally quantified by measuring the visual range, and converting it to a light extinction coefficient (B_{ext}). A high B_{ext} corresponds to high concentrations of light scattering and light-absorbing compounds. The regional haze assessment was done by modeling the increase in the light extinction coefficient (B_{ext}) at Class I areas and comparing the modeled increases to the background B_{ext} values for existing clean days (typically the 90th percentile clearest day). The CALPUFF regional haze analysis results calculate the maximum predicted change in 24-hour extinction coefficient for each Class I area. Changes to extinction were based on seasonal background data for good visibility days and were adjusted with hourly humidity using the techniques described above. The extinction budgets for the higher episodes in most Class I areas are influenced by nitrates, PM_{10}, and, to a lesser extent, sulfates.

Table 3.7-8 lists the modeling results for the Class I areas that were modeled to determine the maximum increase that is predicted to occur in B_{ext} as the result of the Energy Facility functioning under worst case operating conditions. ODEQ and the Federal Land Managers (FLMs) assess whether the Energy Facility could be expected to significantly impair visibility in a Class I area on a case-by-case basis, taking into account geographic extent, intensity, duration, frequency and time of visibility impairment and how these factors correlate with (1) times of visitor use of the Class I area, and (2) the frequency and timing of natural conditions that reduce visibility. The FLMs use screening levels of 5 percent and 10 percent change in light extinction for single source and cumulative source analyses, respectively. Any source whose impacts, by themselves, are modeled to result in B_{ext} of less than 5 percent (as compared to the cleanest background values) will, as a general matter, be considered to result in no significant impairment. The FLM guidance suggests that the source-specific factors should be considered if a facility models its sole source impacts and determines that under worst-case operating conditions a B_{ext} of greater than 5 percent (as compared to the cleanest background values) could occur on 1 or more days.

Measured data for background B_{ext} values at each Class I area were provided by the FLMs. The modeled changes to light extinction attributable to the Energy Facility were less than the 5 percent screening value for all seasons and Class I areas. According to this criterion, changes to visual conditions in the Class I areas would not be perceptible even when the Energy Facility's combustion gas turbines, HRSG duct-burners, and fire pump were emitting at their short-term peak rates.

<u>Recommended Mitigation Measures</u>. No mitigation measures are recommended beyond those included in the proposed project.

<u>Impact 3.7.6. Operation of the Energy Facility could result in odor emissions.</u>

The proposed Energy Facility would not cause significant odors during normal operation. Natural gas delivered to the Energy Facility would not be odorized. However, if it were odorized, it would be contained within the natural gas pipeline and Energy Facility piping system up to the point of use in the combustion gas turbines and HRSG duct burners, where it would be combusted. The M/R Station would contain equipment handling natural gas pressure reduction. This enclosed structure would contain natural gas detection systems as a method for identifying inadvertent leaks within the building. Other natural gas leak detection equipment would be located in other areas within the Energy Facility site where natural gas leaks could collect so the Energy Facility operators could take action to contain the leak and vent the collected natural gas.

Ammonia used in the SCR system for NO_x control would be the only other potential source of odor, and would occur only in the event of an accidental spill or release. Aqueous ammonia would be used for the SCR, because it would release ammonia gas at a slower rate after a spill than anhydrous ammonia, during which containment operations could be implemented. Unreacted ammonia emissions from the HRSG stacks would be at such low concentrations that they would not cause any perceptible odors offsite.

<u>Recommended Mitigation Measures</u>. No mitigation measures are recommended beyond those included in the proposed project.

3.7.3 Cumulative Impacts

Analyses completed for the project indicate that there would be no significant cumulative adverse impacts to air quality from the proposed Energy Facility.

3.7.3.1 Class II Impacts

Criteria pollutant cumulative impacts to air quality in the Class II areas were analyzed in the PSD application for NO_x, PM_{10}, and 1-hour CO. Dispersion modeling was used to demonstrate that impacts from the proposed project combined with significant sources in the area and other background sources were below the ambient air quality standards and PSD increments. NO_2 concentrations were less than half the ambient air quality standard using a background from Portland, Oregon. Background air quality in the area of the Energy Facility site is notably less than the background air quality used in the analysis. Consequently, an increase in sources similar to a level similar to those in the Portland, Oregon, area could be easily tolerated in the area without threatening ambient air quality.

Twenty-four hour PM_{10} concentrations were two-thirds of the ambient air quality standard and annual concentrations less than half the standard, including background values representative of the Klamath Falls area. A notable increase in emissions from other sources could occur and still show that cumulative impacts were below the ambient air quality standards for PM_{10}. Impacts for 1-hour CO combined with a representative background value were slightly more than one-third of the ambient air quality standard. Substantial growth in CO emissions could occur and result in ambient air quality below the standards. Impacts for SO_2 and 8-hour CO for the proposed Energy Facility alone were below the significant impact level defined by EPA and ODEQ and were not analyzed with other sources. Addition of background values and other sources are not expected to impact the 8-hour ambient air quality standard for CO. Emissions of SO_2 from the proposed Energy Facility are quite low, background emissions are quite low, and concentrations are not a concern in the region. Cumulative impacts are not a concern for SO_2 in this area.

3.7.3.2 Other Potential Projects

Section 2.4 discusses other potential projects in the area. Air emissions from these potential future sources are easily incorporated into the background allowances discussed above and no significant cumulative impacts for criteria pollutants from existing or future sources are anticipated.

3.7.3.3 Class I Impacts

In addition, cumulative impacts to Class I areas were analyzed for the EIS by evaluating the potential degradation to visibility resulting from the emissions from the proposed Energy Facility combined with those of other power generating and related facilities currently existing in the area or currently undergoing evaluation by EFSC. These are the major sources of emission with potential to affect distant Class I areas. Other potential sources such as car emissions were not included because they are not expected to have cumulative impacts on distant Class I areas.

Sources and Emissions Modeled

As in the PSD application, the CALPUFF modeling system was used for this analysis, which is the preferred EPA model for analyzing long-range transport of air emissions. In addition to the Energy Facility emission sources, the Class I cumulative effects analysis evaluated emissions from the nearby PG&E Station 14 in Bonanza and the KCP. To be conservative, the projected emissions from the KGF were modeled as well. Applications were submitted in September 2002 to ODEQ and EFSC requesting authorization to construct the KGF. It is unclear when, or if, that authority will be granted and when, or if, the KGF will be built. Typically, unpermitted sources are not included in such cumulative effects analyses. However, in order to best document the worst-case, long-term impacts to the surrounding Class I areas, the KGF was included in this cumulative effects analysis. The sources and emissions modeled in the cumulative effects analysis are summarized in Table 3.7-9.

Visibility Impacts

The visibility cumulative effects analysis was conducted according to guidance provided in the *Interagency Workgroup on Air Quality Modeling Phase 2 Summary Report and Recommendations for Modeling Long-Range Transport Impacts* (EPA-454/R-98-019) (IWAQM2) and the *Federal Land Managers Air Quality Related Values Work Group Phase I Report* (FLAG) (USFS, NPS, USFWS, 2000). The FLAG document indicates that a change in extinction of less than 10 percent, in a Class I area, from the proposed source plus other nearby sources, should be considered an insignificant impact. Therefore, the same criterion was used for this analysis to indicate whether there would be the potential for an adverse cumulative impact. Table 3.7-10 provides a summary of the percent extinctions in each of 11 Class I areas analyzed. In no Class I area would this value exceed 10 percent. It is concluded that there would be no adverse cumulative impact to any Class I area within 200 kilometers (124 miles) of the proposed Energy Facility site. EPA, ODEQ, and the FLMs assume that if no significant impacts are documented at a location within a 200-kilometer radius, the Energy Facility would not significantly impact any Class I areas.

Deposition Impacts

In the PSD analysis, deposition impacts for the project in the Class I areas were compared to screening criteria recommended by the USDA Forest Service. These criteria represent 0.1 percent of the maximum load identified in *Guidelines for Evaluating Air Pollution Impacts on Class I Wilderness Areas in the Pacific Northwest* (USDA Forest Service, May 1992) as the no injury threshold criteria. The full maximum load identified in this document is appropriate for consideration of cumulative impacts. Cumulative emissions of gaseous pollutants NO_x and SO_2, which are the precursors to deposition compounds of concern, are not 1,000 times greater than the emissions analyzed in the PSD application. Therefore, cumulative impacts to deposition are not anticipated.

TABLE 3.7-1
Ambient Air Quality Standards and Prevention of Significant Deterioration Increments

Pollutant	National Primary	National Secondary	State of Oregon	Class I PSD Increments	Class II PSD Increments
Inhalable Particulate Matter (PM_{10})					
Annual Arithmetic Mean	50 $\mu g/m^3$	50 $\mu g/m^3$	50 $\mu g/m^3$	4 $\mu g/m^3$	17 $\mu g/m^3$
24-hour Average	150 $\mu g/m^3$	150 $\mu g/m^3$	150 $\mu g/m^3$	8 $\mu g/m^3$	30 $\mu g/m^3$
Sulfur Dioxide (SO_2)					
Annual Arithmetic Mean	0.03 ppm	NA	0.02 ppm	2 $\mu g/m^3$	20 $\mu g/m^3$
24-hour Average	0.14 ppm	NA	0.10 ppm	5 $\mu g/m^3$	91 $\mu g/m^3$
3-hour Average	NA	0.5 ppm	0.50	25 $\mu g/m^3$	512 $\mu g/m^3$
Carbon Monoxide (CO)					
8-hour Average	9 ppm	NA	9 ppm	NA	NA
1-hour Average	35 ppm	NA	35 ppm	NA	NA
Ozone (O_3)					
1-hour Average	0.12 ppm	0.12 ppm	0.12 ppm	NA	NA
8-hour Average	0.08 ppm	0.08 ppm	NA	NA	NA
Nitrogen Dioxide (NO_2)					
Annual Average	0.05 ppm	0.05 ppm	0.05 ppm	2.5 $\mu g/m^3$	25 $\mu g/m^3$
Lead (Pb)					
Quarterly Average	1.5 $\mu g/m^3$	1.5 $\mu g/m^3$	1.5 $\mu g/m^3$	NA	NA

Annual standards never to be exceeded; short-term standards not to be exceeded more than once per year unless otherwise noted.

$\mu g/m^3$ = micrograms per cubic meter
ppm = parts per million
NA = not applicable

TABLE 3.7-2
Regional Class I Areas

Class I Area	Distance from Energy Facility Site (kilometers)	State
Three Sisters Wilderness	189	Oregon
Crater Lake National Park	87	Oregon
Diamond Peak Wilderness	156	Oregon
Mountain Lakes Wilderness	58	Oregon
Gearhart Wilderness	52	Oregon
Lava Beds National Monument	41	California
South Warner Wilderness	125	California
Thousand Lakes Wilderness	159	California
Marble Mountain Wilderness	152	California
Lassen Volcanic National Park	176	California
Caribou Wilderness	180	California

TABLE 3.7-3
Maximum Short-Term and Annual Criteria Pollutant Emission Rates

Pollutant	Maximum Short-Term Emission Rate from Fire Pump (lb/hr)	Maximum Short-Term Emission Rate Per Combustion Turbine and HRSG (lb/hr)	Maximum Annual Emission Rate for Energy Facility (tons/yr)
NO_X (as NO_2)	9.06	22.8	354
CO	1.95	19.0	465
SO_2	0.60	1.0	16
VOC	0.74	7.1	96
PM	0.64	14.0	242
PM_{10}	0.64	14.0	242

NO_2 = nitrogen dioxide
NO_x = nitrogen oxide
PM_{10} = particulates less than 10 microns in diameter
SO_2 = sulfur dioxide

TABLE 3.7-4
Modeled Ambient Concentrations for Criteria Pollutants

Pollutant	Averaging Period	Maximum Predicted Concentration ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	Ambient Air Quality Standard[2] ($\mu g/m^3$)	PSD Class II Increment[3] ($\mu g/m^3$)
NO_2	Annual	6.30[1]	1	33.9	40.2	100	25
CO	1-Hour	3,078[1]	2,000	9,620	12,698	40,000	NA
CO	8-Hour	263	500	NA	NA	10,000	NA
PM_{10}	24-Hour	13.11[1]	1	80	93.11	150	30
PM_{10}	Annual	1.55[1]	0.2	18.1	19.65	50	17

[1]Project-only impacts for this pollutant and averaging period exceeded the significant impact level. Maximum predicted concentration includes competing sources.

[2]Compliance assessed by comparing to Total Concentration.

[3]Compliance assessed by comparing to Maximum Predicted Concentration.

$\mu g/m^3$ = micrograms per cubic meter
CO = carbon monoxide
NA = not applicable (because the maximum predicted concentration is below the significant impact level)
NO_2 = nitrogen dioxide; note that modeled value was multiplied by 0.75 to convert from NO_x to NO_2
PM_{10} = particulate matter less than 10 microns in diameter
PSD = Prevention of Significant Deterioration

TABLE 3.7-5
Summary of Hazardous Air Pollutant Emissions

Pollutant	Annual Emission Rate for Combustion Turbines and Duct Burners* (tons/yr)	Annual Emission Rate for Fire Pump (lb/hr)	Annual Emissions (tons/yr)
Benzene	0.17	5.0 E-05	0.17
Formaldehyde	2.96	6.3 E-05	2.98
Hexane	6.85	--	7.33
Naphthalene	0.02		0.02
Toluene	1.73	2.2 E-05	1.73
Acetaldehyde	0.53	4.1 E-05	0.53
Acrolein	0.08	--	0.08
Ethylbenzene	0.42	--	0.42
PAH	0.03	9.0 E-06	0.03
Xylenes (total)	0.85	1.5 E-05	0.85
Dichlorobenzene	0.005	--	0.005
Arsenic	0.002		0.002
Cadmium	0.009		0.010
Chromium	0.012		0.012
Cobalt	0.001		0.001
Manganese	0.003		0.003
Mercury	0.002		0.002
Nickel	0.018		0.018

* Hazardous air pollutant (HAP) emission rates assume oxidation catalyst destruction efficiency of 55 percent for volatile organic HAPs.

TABLE 3.7-6
Modeled Class I Ambient Air Quality Results (Energy Facility Alone)

Area	PM_{10} Annual ($\mu g/m^3$)	PM_{10} 24-Hour ($\mu g/m^3$)	NO_X Annual ($\mu g/m^3$)
Three Sisters Wilderness	0.0006	0.014	0.0001
Crater Lake National Park	0.0028	0.14	0.0019
Diamond Peak Wilderness	0.0008	0.022	0.0002
Mountain Lakes Wilderness	0.0057	0.16	0.005
Gearhart Wilderness	0.011	0.12	0.011
Lava Beds National Monument	0.0032	0.065	0.0011
South Warner Wilderness	0.002	0.027	0.0012
Thousand Lakes Wilderness	0.0014	0.039	0.0007
Marble Mountain Wilderness	0.0013	0.037	0.0007
Lassen Volcanic National Park	0.001	0.033	0.0004
Caribou Wilderness	0.0009	0.015	0.0004
EPA Proposed Class I Significance Level	**0.2**	**0.3**	**0.1**
Class I Increment	**4**	**8**	**2.5**

$\mu g/m^3$ = micrograms per cubic meter
EPA = U.S. Environmental Protection Agency
NO_X = nitrogen oxide
PM_{10} = particulates less than 10 microns in diameter

TABLE 3.7-7
Summary of Total Nitrogen and Sulfur Deposition Results (Energy Facility Alone)

Area	Total N kg/(hectare*yr)	Total S kg/(hectare*yr)
Three Sisters Wilderness	0.0003	0.00006
Crater Lake National Park	0.0008	0.0001
Diamond Peak Wilderness	0.0003	0.00006
Mountain Lakes Wilderness	0.002	0.0002
Gearhart Wilderness	0.0058	0.001
Lava Beds National Monument	0.0009	0.0002
South Warner Wilderness	0.0008	0.0001
Thousand Lakes Wilderness	0.0005	0.00007
Marble Mountain Wilderness	0.0004	0.00007
Lassen Volcanic National Park	0.0004	0.00006
Caribou Wilderness	0.0004	0.00005

kg/(hectare*yr) = kilograms per hectare per year
N = nitrogen
S = sulfur

TABLE 3.7-8
Visibility Analysis Results—Maximum Percent Change in Extinction (Energy Facility Alone)

Area	Day	Year	Receptor Coordinate X (km)*	Receptor Coordinate Y (km)*	B_{ext} Modeled (1/Mm)	B_{ext} Background (1/Mm)	Extinction Change (%)
Three Sisters Wilderness	344	1998	201.0	202.656	0.111	17.242	0.64
Crater Lake National Park	344	1998	204.848	93.0	0.659	17.236	3.82
Diamond Peak Wilderness	344	1998	201.0	169.326	0.155	17.242	0.9
Mountain Lakes Wilderness	350	1998	201.51	44.5	0.811	17.056	4.76
Gearhart Wilderness	10	1999	296.0	70.56	0.447	16.876	2.65
Lava Beds National Monument	171	1998	251.6	-14.211	0.187	15.958	1.17
South Warner Wilderness	13	1999	355.073	-54.5	0.203	16.672	1.22
Thousand Lakes Wilderness	8	1999	246.135	-136.258	0.239	16.786	1.42
Marble Mountain Wilderness	357	1998	125.1	-58.817	0.338	16.99	1.99
Lassen Volcanic National Park	8	1999	248.601	-157.379	0.189	16.786	1.12
Caribou Wilderness	339	1998	277.47	-155.593	0.149	16.546	0.9

* Lambert conformal coordinate system with a reference north latitude of 46 degrees and a reference west longitude of 121 degrees and standard parallels of 42.5 and 48 degrees north latitude and standard meridian of 121 degrees west longitude.

B_{ext} = light extinction coefficient
km = kilometers
1/Mm = inverse megameters

TABLE 3.7-9
Sources Included in Cumulative Impacts Analysis

Facility	Source	NO_x (lb/hr)	SO_2 (lb/hr)	PM_{10} (lb/hr)
COB Energy Facility	HRSG 1-4[1]	22.3	1	14
	Gas Heaters 1-4[1]	0.18	0.001	0.014
	Fire Water Pump	0.38	0.025	0.0265
PGE Transmission NW Corporation	Turbine 14[1]	33.2	0.3	0.7
	Turbine 14[2]	45.6	0.3	0.8
Klamath Cogeneration Project[3]	2 HRSG[2]	33	3.3	2
Klamath Generation Facility[3,4]	CT 1-2[2]	7.2	2.3	4.2
	Generator	0.00925	0.045	0.00604
	Fire pump	0.175	0.095	0.0123

[1] Emissions shown are for each of four units.
[2] Emissions shown are for each of two units.
[3] Emissions modeled derived from individual facility air permit applications.
[4] Klamath Generation Facility is permitted, but not yet operating.

-- = No emissions of pollutant from this source.

TABLE 3.7-10
Cumulative Visibility Analysis Results—Maximum Percent Extinction Change

Area	Day	Year	Receptor Coordinate X (km)*	Receptor Coordinate Y (km)*	B_{ext} Modeled (1/Mm)	B_{ext} Background (1/Mm)	Extinction Change (%)
Three Sisters Wilderness	344	1998	184.263	231.959	0.215	17.242	1.24
Crater Lake National Park	344	1998	204.848	93.0	1.094	17.236	6.35
Diamond Peak Wilderness	344	1998	189.0	166.071	0.301	17.242	1.742
Mountain Lakes Wilderness	3	1999	201.881	35.437	1.263	17.074	7.40
Gearhart Wilderness	6	1999	306.0	58.215	0.782	16.876	4.64
Lava Beds National Monument	234	1998	244.238	-18.1	0.240	15.904	1.51
South Warner Wilderness	13	1999	355.073	-54.5	0.341	16.672	2.05
Thousand Lakes Wilderness	8	1999	243.239	-137.576	0.424	16.786	2.53
Marble Mountain Wilderness	357	1998	121.013	-51.4	0.708	16.99	4.17
Lassen Volcanic National Park	339	1998	272.17	-152.876	0.388	16.618	2.34
Caribou Wilderness	339	1998	275.052	-155.605	0.361	16.546	2.18

* Lambert conformal coordinate system with a reference north latitude of 46 degrees and a reference west longitude of 121 degrees and standard parallels of 42.5 and 48 degrees north latitude and standard meridian of 121 degrees west longitude.

B_{ext} = light extinction coefficient
km = kilometers
1/Mm = inverse megameters

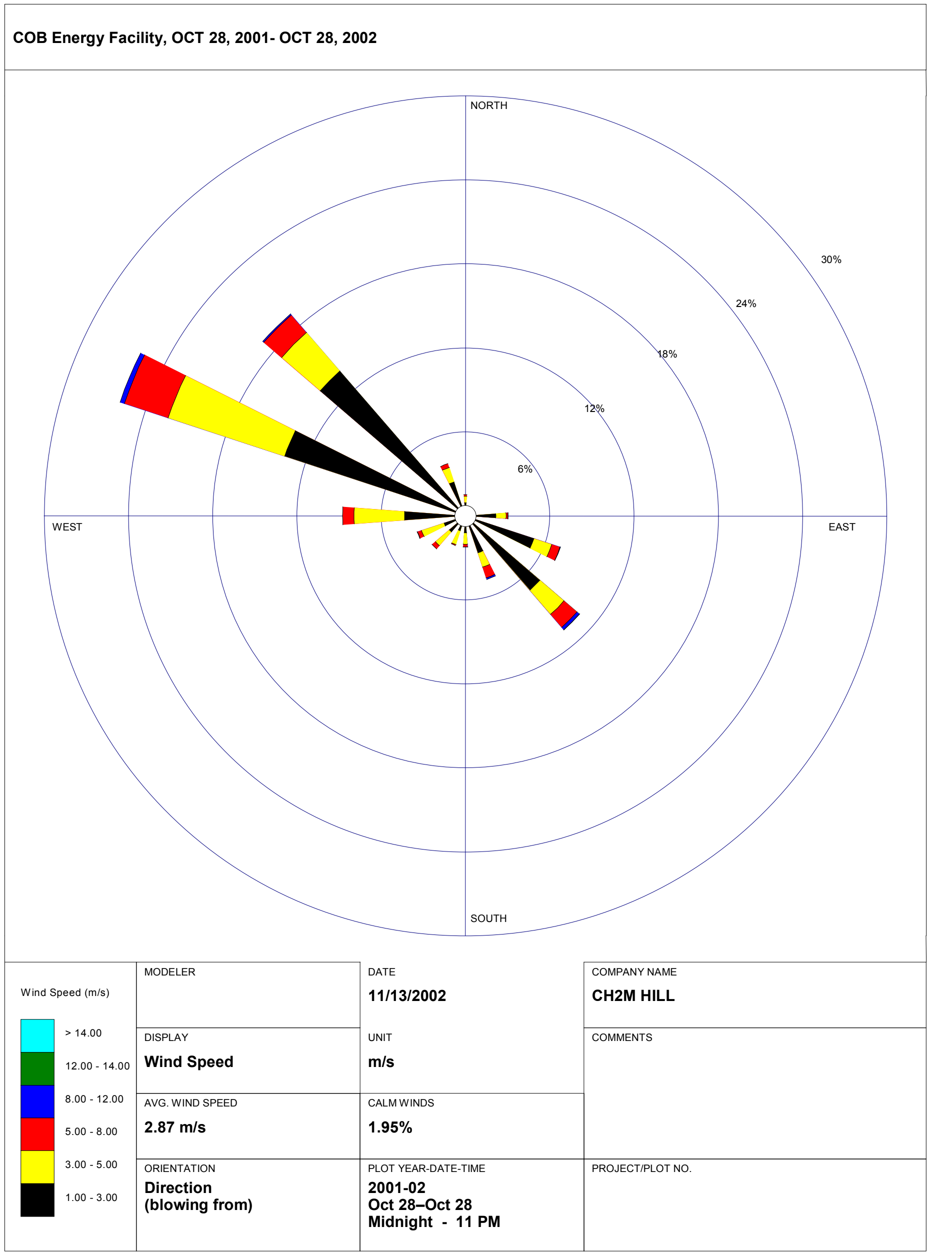

FIGURE 3.7-1
Annual Windrose of the Meteorological Data Set